Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Phone: (304) 926-0475 • FAX: (304) 926-0479

Earl Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

January 5, 2017

CERTIFIED MAIL
91 7199 9991 7037 0977 7425

Mr. Ramon L. Callaghan, Jr.
Vice President of EHS
Ergon - West Virginia, Inc.
9995 Ohio River Blvd., Route 2 South
Newell, WV 26050

RE: **Permit Issuance**
Ergon - West Virginia, Inc.
Newell Refinery
Permit No. R13-2334AA
Plant ID No. 029-00008

Dear Mr. Callaghan:

Your application for a permit as required by Section 5 of 45CSR13 - "Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permit, General Permit, and Procedures for Evaluation" has been approved. The enclosed permit R13-2334AA is hereby issued pursuant to Subsection 5.7 of 45CSR13. Please be aware of the notification requirements in the permit which pertain to commencement of construction, modification, or relocation activities; startup of operations; and suspension of operations.

Please note, the source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

Should you have any questions or comments, please contact me at (304) 926-0499, extension 1219.

Sincerely,

Joe Kessler, PE
Engineer

Enclosures

West Virginia Department of Environmental Protection
Division of Air Quality

Earl Ray Tomblin
Governor

Randy C. Huffman
Cabinet Secretary

Class II Administrative Update

R13-2334AA

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45 C.S.R. 13 — Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation. The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:

Ergon - West Virginia, Inc.

Newell Refinery

029-00008

William F. Durham
Director

Issued: January 5, 2017

This permit will supercede and replace Permit R13-2334Z issued on November 30, 2016.

Facility Location:	Newell, Hancock County, West Virginia
Mailing Address:	9995 Ohio River Blvd Newell, WV 26050
Facility Description:	Petroleum Refinery
SIC/NAICS Codes:	2911/324110
UTM Coordinates:	531.0 km Easting • 4,495.1 km Northing • Zone 17
Latitude/Longitude:	40.609173/-80.629196
Permit Type:	Class II Administrative Update
Description of Change:	Addition of a new 126,000 bio-diesel storage tank.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§ 22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §22-5-14.

The source is subject to 45CSR30. Changes authorized by this permit must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

Unless otherwise stated, WVDEP DAQ did not determine whether the applicant is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart BBBBBB.

Table of Contents

1.0 Emission Units

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed /Modified	Design / Permitted Capacity	Control Device
CDU	CDU	Crude Distillation Unit	1972/ 2015	839,500 bbls/mo	00A-01
001-01	H-101R	CDU Atmospheric Heater; refinery fuel gas/natural gas blend	2012	54.5 MMBtu/hr	n/a
001-02	H-102R	CDU Vacuum Heater; refinery fuel gas/natural gas blend	2012	29.4 MMBtu/hr	n/a
002-01	H-201	PDR Heater; refinery fuel gas/natural gas blend or fuel oil	1972	6.6 MMBtu/hr	n/a
003-01	MEK-TOL	Solvent Dewaxing Unit	1972	NA	n/a
004-01	H-500S	H500 Series Heaters Unifiner/Platformer Unit; refinery fuel gas/natural gas blend	1972/ 2015	59.6 MMBtu/hr	n/a
004-02	H-501R	Unifiner Charge Heater	2013	11.5 MMBtu/hr	n/a
005-01	H-600S	H600 Series Heaters, ISOMAX Unit; refinery fuel gas/natural gas blend	1972	41.6 MMBtu/hr	n/a
005-02	H-441	Hydrogen Plant Heater; natural gas	1972	12.3 MMBtu/hr	n/a
006-01	H-701	VFU Heater; refinery fuel gas/natural gas blend	1983	12.1 MMBtu/hr	n/a
007-01	Boiler A	Boiler A; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	n/a
007-02	Boiler B	Boiler B; refinery fuel gas/natural gas blend	1972	159.50 MMBtu/hr	n/a
007-03	Boiler C	Boiler C; refinery fuel gas/natural gas blend	2000	95 MMBtu/hr	n/a
009-01	T Load	Truck Loading	1972/ 2012/ 2013	397.8 MMgal/yr	00A-02*
009-02	MLD	Marine Barge Loading	1972/ 2012	460.7 MMgal/yr	00A-04**
00A-01	F1	Main Flare	1972	NA	n/a
00A-03	F2	Sour Gas Flare	1972	NA	n/a
00A-02	OXIDIZER	Thermal Oxidizer.	1994/ 2012/ 2013	17,346 MMBtu/yr 98.7% min efficiency	n/a
00B-01	WWT	Wastewater Treatment Plant	1972	600 gpm	00A-03

00B-02	**EQLEAKS**	**Equipment Leak Fugitives**	**NA**	**NA**	**n/a**
00D-01	**Dehy Htr**	**Dehydration Heater**	**1991**	**0.59 MMBtu/hr**	**n/a**
00D-02	**Still**	**Glycol Dehydration Still**	**1991**	**N/A**	**n/a**
EPN 01	**H-901**	**DHT Heater**	**2005**	**27.5 MMBtu/hr**	**n/a**
EPN 03	**H-1101**	**Hydrogen Plant Heater**	**2005**	**38.8 MMBtu/hr**	**n/a**
00A-04	**MLDOX**	**Barge Loading Thermal Oxidizer**	**2012**	**59.0 MMBtu/hr 98% min efficiency**	**n/a**

Tanks

Emission Unit ID	Emission Point ID	Emission Unit Description	Contents	Designation	Year Installed	Design / Permitted Capacity	Control Device
4000	**TK-4000**	**External floating roof; mechanical shoe**	**crude oil**	**Kb**	**1992/ 2012**	**2,310,000 gallons**	**n/a**
4001	**TK-4001**	**External floating roof; mechanical shoe**	**crude oil**	**Kb**	**1973/ 2012**	**2,310,000 gallons**	**n/a**
4002	**TK-4002**	**External floating roof; mechanical shoe**	**heavy/ kerosene**		**1970**	**2,310,000 gallons**	**n/a**
4003	**TK-4003**	**External floating roof; mechanical shoe**	**heavy / kerosene**		**1970**	**2,310,000 gallons**	**n/a**
4004	**TK-4004**	**External floating roof; mechanical shoe**	**gasoline**		**1971/ 2013**	**1,050,000 gallons**	**n/a**
4005	**TK-4005**	**External floating roof; mechanical shoe**	**gasoline**		**1971**	**1,050,000 gallons**	**n/a**
4006	**TK-4006**	**External floating roof; mechanical shoe**	**gasoline**		**1971/ 2013**	**1,050,000 gallons**	**n/a**
4007	**TK-4007**	**Fixed roof**	**heavy**		**1971**	**2,310,000 gallons**	**n/a**
4008	**TK-4008**	**Fixed roof**	**heavy**		**1970**	**1,260,000 gallons**	**n/a**

Emission Unit ID	Emission Point ID	Emission Unit Description	Contents	Designation	Year Installed	Design / Permitted Capacity	Control Device
4009	TK-4009	Fixed roof	heavy / kerosene		1971	1,260,000 gallons	n/a
4010	TK-4010	Fixed roof	heavy		1970	1,260,000 gallons	n/a
4011	TK-4011	Fixed roof	heavy / kerosene		1971	1,239,568 gallons	n/a
4012	TK-4012	Internal floating roof; mechanical shoe	gasoline		1971	630,000 gallons	n/a
4013	TK-4013	Internal floating roof; mechanical shoe	gasoline		1971	630,000 gallons	n/a
4014	TK-4014	External floating roof; mechanical shoe	gasoline		1971/ 2013	315,000 gallons	n/a
4015	TK-4015	External floating roof; mechanical shoe	gasoline		1971/ 2013	315,000 gallons	n/a
4016	TK-4016	External floating roof; mechanical shoe	gasoline		1971	315,000 gallons	n/a
4017	TK-4017	Fixed roof	heavy		1971	840,000 gallons	n/a
4018	TK-4018	Fixed roof	heavy		1971	704,970 gallons	n/a
4019	TK-4019	Fixed roof	heavy		1971	704,970 gallons	n/a
4020	TK-4020	Fixed roof	heavy		1971	840,000 gallons	n/a
4021	TK-4021	Fixed roof	heavy		1971	840,000 gallons	n/a
4022	TK-4022	Fixed roof	heavy		1971	571,200 gallons	n/a
4023	TK-4023	Fixed roof	heavy		1971	571,200 gallons	n/a
4024	TK-4024	Fixed roof	heavy		1970	840,000 gallons	n/a
4025	TK-4025	Fixed roof	heavy		1970	840,000 gallons	n/a
4026	TK-4026	Fixed roof	heavy		1970	840,000 gallons	n/a

Emission Unit ID	Emission Point ID	Emission Unit Description	Contents	Designation	Year Installed	Design / Permitted Capacity	Control Device
4027	TK-4027	Fixed roof	heavy		1971	840,000 gallons	n/a
4028	TK-4028	Fixed roof	heavy		1970	210,000 gallons	n/a
4029	TK-4029	Fixed roof	heavy		1971	65,100 gallons	n/a
4030	TK-4030	Fixed roof	heavy		1971	65,100 gallons	n/a
4031	TK-4031	Fixed roof	heavy		1971	315,000 gallons	n/a
4032	TK-4032	Fixed roof	heavy		1971	315,000 gallons	n/a
4033	TK-4033	Fixed roof	heavy		1970	315,000 gallons	n/a
4034	TK-4034	Fixed roof	heavy	Kb	1998	840,000 gallons	n/a
4035	TK-4035	Fixed roof	heavy	Ka	1983	840,000 gallons	n/a
4036	TK-4036	Fixed roof	heavy	K	1973	315,000 gallons	n/a
4037	TK-4037	Fixed roof	heavy	K	1973	315,000 gallons	n/a
4038	TK-4038	Fixed roof	heavy	K	1976	840,000 gallons	n/a
4039	TK-4039	Fixed roof	heavy	K	1977	1,260,000 gallons	n/a
4040	TK-4040	Fixed roof	heavy	Ka	1978	630,000 gallons	n/a
4041	TK-4041	Fixed roof	heavy		1973	630,000 gallons	n/a
4042	TK-4042	Fixed roof	heavy	Ka	1978	630,000 gallons	n/a
4043	TK-4043	Fixed roof	heavy	Ka	1978	630,000 gallons	n/a
4044	TK-4044	Fixed roof	heavy	Ka	1982	1,260,000 gallons	n/a
4045	TK-4045	Fixed roof	heavy	Ka	1982	630,000 gallons	n/a
4046	TK-4046	Fixed roof	heavy	Ka	1982	630,000 gallons	n/a

Emission Unit ID	Emission Point ID	Emission Unit Description	Contents	Designation	Year Installed	Design / Permitted Capacity	Control Device
4047	TK-4047	Fixed roof	heavy	Kb	1986	1,260,000 gallons	n/a
4048	TK-4048	Fixed roof	heavy	Kb	1986	504,000 gallons	n/a
4050	TK-4050	Internal floating roof; mechanical shoe	gasoline	Kb	1993/ 2013	630,000 gallons	n/a
4051	TK-4051	Fixed roof	heavy	Kb	1996	1,260,000 gallons	n/a
4052	TK-4052	Fixed roof	ethanol		1972	30,240 gallons	n/a
4053	TK-4053	Fixed roof	ethanol		1972	30,240 gallons	n/a
4054	TK-4054	Fixed roof	heavy / kerosene	Kb	1998	625,000 gallons	n/a
4055	TK-4055	Fixed roof	heavy / kerosene	Kb	1998	625,000 gallons	n/a
4056	TK-4056	Fixed roof	heavy / kerosene	Kb	1999	625,000 gallons	n/a
4057	TK-4057	Fixed roof	heavy / kerosene	Kb	1999	625,000 gallons	n/a
4060	TK-4060	Internal floating roof; mechanical shoe	crude oil	Kb	1999/ 2015	5,040,000 gallons	n/a
4061	TK-4061	Internal floating roof; mechanical shoe	crude oil	Kb	2008/ 2015	5,040,000 gallons	n/a
4062	TK-4062	Internal floating roof; mechanical shoe	light crude oil w/vapor pressure ≤ 11.0 psia	Kb	2008/ 2012	5,040,000 gallons	n/a
4063	TK-4063	Internal floating roof; mechanical shoe	light crude oil w/vapor pressure ≤ 11.0 psia	Kb	2012	5,040,000 gallons	n/a
4066	TK-4066	Fixed Roof	biodiesel		2011	40,000 gallon	n/a
4069	TK-4069	Fixed Roof	biodiesel		2017	126,000 gallons	n/a
4103	TK-4103	Fixed roof	heavy		1970	127,000 gallons	n/a

Emission Unit ID	Emission Point ID	Emission Unit Description	Contents	Designation	Year Installed	Design / Permitted Capacity	Control Device
4104	**TK-4104**	**Fixed roof**	**heavy**		**1970**	**127,000 gallons**	**n/a**
00A-03	**CARBON BED**	**Carbon Bed Adsorber**			**2002**	**6,000 cfm**	**n/a**
Process Vessels							
303	**TK-303**	**Fixed roof**	**MEK**		**1970**	**7,875 gallons**	**n/a**
304	**TK-304**	**Fixed roof**	**Toluene**		**1970**	**7,875 gallons**	**n/a**
NS-FUG	**NS-FUG**	**Naphtha Splitter Fugitives**	**Naphtha**		**2011**	**Not Applicable**	**n/a**
ISOM	**ISOM**	**Processing Unit; Benzene Reduction**	**n/a**		**2012**	**21.6 Mmgal/yr**	**n/a**
ADU	**NH3OX**	**Ammonia Destruction Unit**	**N/A**		**2015**	**N/A**	**00A-05**
00A-05	**NH3OX**	**Ammonia Destruction Unit Thermal Oxidizer**	**N/A**		**2015**	**6.6 MMBtu/hr** **99.9% DRE**	**N/A**
ADUFUG	**ADUFUG**	**Ammonia Destruction Unit Fugitives**	**N/A**		**2015**	**N/A**	**N/A**
PL-FUG	**PL-FUG**	**Platformer Expansion Fugitives**	**N/A**		**2015**	**N/A**	**N/A**
YNGL-FUG	**YNGL-FUG**	**Y-Grade NGL Fugitives**	**N/A**		**2015**	**N/A**	**N/A**

*** Control Device for Gasoline Loading Only**
**** Control Device for Gasoline and Light Crude Oil Loading Only**

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45 CSR § 30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. ***or*** **CFR**	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. ***or*** **CSR**	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
dscm	Dry Standard Cubic Meter
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr	Pounds per Hour
LDAR	Leak Detection and Repair
M	Thousand
MACT	Maximum Achievable Control Technology
MDHI	Maximum Design Heat Input
MM	Million
MMBtu/hr ***or*** **mmbtu/hr**	Million British Thermal Units per Hour
MMCF/hr ***or*** **mmcf/hr**	Million Cubic Feet per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5μm in diameter
PM_{10}	Particulate Matter less than 10μm in diameter
Ppb	Pounds per Batch
pph	Pounds per Hour
ppm	Parts per Million
Ppmv or ppmv	Parts per million by volume
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Law W.Va. Code §§22-5-1 et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation;*

2.4. Term and Renewal

2.4.1. This permit supercedes and replaces previously issued Permit R13-2334W. This permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any applicable legislative rule.

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Applications R13-2334 through R13-2334AA, and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.11 and 13-10.3]

2.5.2. This permit supercedes and replaces R13-2334Z. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses and/or approvals from other agencies; i.e., local, state and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13. **[45CSR§13-4]**

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10. Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;
b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and,

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emission, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5. The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1 State-Enforceable only.]

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45 C.S.R. 11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements

[Reserved]

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4 or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4 or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

   1. The permit or rule evaluated, with the citation number and language;
   2. The result of the test for each permit or rule condition; and,
   3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State-Enforceable only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class with postage prepaid to the address(es) set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

If to the DAQ:

Director
WVDEP
Division of Air Quality
601 57th Street, SE
Charleston, WV 25304-2345

If to the USEPA:

Associate Director
Office of Air Enforcement and Compliance
Assistance
(3AP20)
U. S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

3.5.4. **Operating Fee.**

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a Certified Emissions Statement (CES) and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements [Fuel Burning Units (Boilers A, B, & C, Heaters H-101R, H-102R, H-201, H-501R, H-500s, H-600s, H-441, H-701, H-901, & H-1101)]

Emission Unit	Limits and Standards Section 4.1	Monitoring Section 4.2	Testing Section 4.3	Recordkeeping Section 4.4	Reporting Section 4.5
Boiler A	1,2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 26, 27	1, 2, 3	n/a	1, 2, 3, 4, 5, 6, 7, 8, 9, 14	1, 2
Boiler B	1,2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 26, 27	1, 2, 3	n/a	1, 2, 3, 4, 5, 6, 7, 8, 9, 14	1, 2
Boiler C	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 14, 15, 26, 27	1	n/a	1, 2, 3, 4, 5, 6, 7, 8, 10, 14	1, 3
H-101R	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 16, 17, 18, 19	1, 7	1	1, 2, 3, 4, 5, 6, 7, 8, 11, 12, 13, 14, 18	1, 2, 5
H-102R	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 16, 17, 18, 19	1, 7	1	1, 2, 3, 4, 5, 6, 7, 8, 11, 12, 13, 14, 18	1, 2, 5
H-201	1, 2, 3, 4, 5, 20, 21, 26, 27	1, 2, 3	n/a	1, 2, 3, 4, 11, 12, 13, 14	n/a
H-441	1, 2, 3, 4, 5, 6, 7, 8, 9, 20, 21	1	n/a	1, 2, 3, 4, 5, 6, 11, 12, 13	1
H-701	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 20, 21, 26, 27	1	n/a	1, 2, 3, 4, 5, 6, 7, 8, 11, 12, 13, 14	1
H-501R	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 16, 17, 18, 19	1, 7	1	1, 2, 3, 4, 5, 6, 7, 8, 11, 18	1, 2, 5
H-500S	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 17, 22, 26, 27	1, 2, 3, 7	n/a	1, 2, 3, 4, 5, 6, 7, 8, 11, 12, 13, 14, 18	1, 2, 5
H-600S	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 22, 26, 27	1, 2, 3	n/a	1, 2, 3, 4, 5, 6, 7, 8, 11, 12, 13, 14	1, 2

H-901	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 23, 24, 25, 26, 27	1, 4, 5, 6	n/a	1, 2, 3, 4, 5, 6, 14, 15, 16, 17	1, 2, 4
H-1101	1, 2, 3, 4, 5, 6, 7, 8, 9, 23, 24, 25	1, 4, 5, 6	n/a	1, 2, 3, 4, 5, 6, 15, 16, 17	1, 4

4.1. Limitations and Standards

All boilers and heaters

4.1. 1. No person shall cause, suffer, allow or permit emission of smoke and/or particulate matter into the open air from any fuel burning unit which is greater than ten (10) percent opacity based on a six minute block average.
[45CSR§2-3.1.]

4.1. 2. In the event of an unavoidable shortage of fuel having characteristics or specifications necessary for a fuel burning unit to comply with the visible emission standards set forth in 45CSR§2-3.1. or any emergency situation or condition creating a threat to public safety or welfare, the Director may grant an exception to the otherwise applicable visible emission standards for a period not to exceed fifteen (15) days, provided that visible emissions during the exception period do not exceed a maximum six (6) minute average of thirty (30) percent and that a reasonable demonstration is made by the owner or operator that the emission standards under 45CSR§2-4.1.b. will not be exceeded during the exemption period.
[45CSR§2-10.1.]

4.1. 3. In the event a fuel burning unit employing a flue gas desulphurization system must by-pass such system because of necessary planned or unplanned maintenance, visible emissions may not exceed twenty percent (20%) opacity during such period of maintenance. The Director may require advance notice of necessary planned maintenance, including a description of the necessity of the maintenance activity and its expected duration and may limit the duration of the variance or the amount of the excess opacity exception herein allowed. The Director shall be notified of unplanned maintenance and may limit the duration of the variance or the amount of excess opacity exception allowed during unplanned maintenance.
[45CSR§2-10.2.]

4.1. 4. The facility shall not burn Fuel Oil in any combustion unit, except during periods of natural gas curtailment and/or during periods of DOT required maintenance of the natural gas pipeline in which the facility shall burn only LPG or low sulfur distillate (e.g. No. 2 oil at less than 0.5% sulfur). Note: Fuel Oil is defined as any liquid fossil fuel with sulfur content greater than 0.05% by weight.

4.1. 5. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.11.]

All Boilers and Heaters Except H-201

4.1.6. No person shall cause, suffer, allow or permit the discharge of particulate matter into the open air in excess of the following:

Emission Unit	PM Emission Limit
Boiler A	14.36 pounds per hour
Boiler B	14.36 pounds per hour
Boiler C	8.55 pounds per hour
H-101R	4.91 pounds per hour
H-102R	2.65 pounds per hour
H-501R	1.04 pounds per hour
H-500s	5.36 pounds per hour
H-600s	3.74 pounds per hour
H-441	1.11 pounds per hour
H-701	1.09 pounds per hour
H-901	2.48 pounds per hour
H-1101	3.49 pounds per hour

[45CSR§2-4.1.b.]

4.1.7. The visible emission standards set forth in 45CSR§2-3 shall apply at all times except in periods of start-ups, shutdowns and malfunctions. Where the Director believes that start-ups and shutdowns are excessive in duration and/or frequency, the Director may require an owner or operator to provide a written report demonstrating that such frequent start-ups and shutdowns are necessary.
[45CSR§2-9.1.]

4.1.8. At all times, including periods of start-ups, shutdowns and malfunctions, owners and operators shall, to the extent practicable, maintain and operate any fuel burning unit(s) including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, visible emission observations, review of operating and maintenance procedures and inspection of the source.
[45CSR§2-9.2. , 45CSR§16, and §60.11(d), NSPS Subpart A]

4.1.9. Compliance with the allowable sulfur dioxide emission limitations from fuel burning units shall be based on a continuous twenty-four (24) hour averaging time. The owner and/or operator of a fuel burning unit shall not allow emissions to exceed the weight emissions standards for sulfur dioxide as set forth in this rule, except during one (1) continuous twenty-four (24) hour period in each calendar month and during this one (1) continuous twenty-four hour period said owner and/or operator shall not allow emissions to exceed such weight emission standards by more than ten percent (10%) without causing a violation of this rule. A continuous twenty-four (24) hour period is defined as one (1) calendar day.
[45CSR§10-3.8.]

Boilers A, B, and C, Heaters H-101R, H-102R, H-501R, H-500S, H-600S, H-701, H-901

4.1. 10. At the request of the Director the owner and/or operator of a source shall install such stack gas monitoring devices as the Director deems necessary to determine compliance with the provisions of 45CSR10. The data from such devices shall be readily available at the source location or such other reasonable location that the Director may specify. At the request of the Director, or his or her duly authorized representative, such data shall be made available for inspection or copying. Failure to promptly provide such data shall constitute a violation of this rule. **[45CSR§10-8.2.a.]**

4.1. 11. The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) shall demonstrate compliance with sections 3, 4 and 5 of 45CSR10 by testing and /or monitoring in accordance with one or more of the following: 40 CFR Part 60, Appendix A, Method 6, Method 15, continuous emissions monitoring systems (CEMS) or fuel sampling and analysis as set forth in an approved monitoring plan for each emission unit.
[45CSR§10-8.2.c.]

Boilers A and B

4.1. 12. The permittee shall monitor compliance with 45CSR§2-3 in an approved monitoring plan (see Appendix A) for each emission unit. Such plans shall include, but not be limited to, one or more of the following: continuous measurement of emissions, monitoring of emission control equipment, periodic parametric monitoring, or such other monitoring as approved by the Director.
[45CSR§2-8.2.]

4.1. 13. The combined emissions from Boiler A and Boiler B (Emission Point ID Nos. A & B, which is a common stack) shall not exceed those listed below. NOx limits (based on a three hour averaging period) for each boiler shall be as follows: Boiler A - 0.058 lb/mmBTU and Boiler B - 0.058 lb/mmBTU.

Pollutant	Emission Rate	
	TPM	TPY
CO	11.51	115.07
NO_x	8.10	81.04
PM	1.04	10.42
SO_2	0.81	8.06
VOC	0.75	7.53

Boiler C

4.1. 14. Boiler C shall be equipped with low NO_x burners. Emissions from Boiler C (Emission Point ID No. C) shall not exceed the limits in the following table. Compliance with the SO_2 limit shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.

Pollutant	Emission Rate	
	Tons per Month (TPM)	Tons per Year (TPY)
CO	3.43	34.27
NO_x	2.08	20.81
PM	0.31	3.10

SO_2	0.24	2.41
VOC	0.22	2.24

Boiler C and Heater H-101R

4.1.15. NO_x limits on heaters and boilers greater than 40 mmBTU/hr heat input capacity shall be as follows:

i. Boiler C - 0.050 lb/mmBTU (based on a three-hour averaging period) and

ii. H-101R - 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis
[ii - 40 CFR § 60.102a (g)(2)(i)(A), NSPS Subpart Ja].

Heaters H-101R, H-102R, H-500S, and H-501R

4.1.16. Process heaters H-101R, H-102R, and H-501R shall be equipped with low NO_x burners. Combined emissions from H-101R and H-102R shall not exceed those listed below. Emissions from H-501R shall not exceed those listed below.

	H-101R and H-102R		H-501R	
Pollutant	Emission Rate		Emission Rate	
	TPM	TPY	TPM	TPY
CO	1.11	11.02	0.15	1.50
NO_x	2.40	23.89	0.33	3.27
PM	0.63	2.76	0.04	0.38
PM10	0.60	2.62	0.04	0.35
PM2.5	0.59	2.56	0.04	0.35
SO_2	0.75	7.43	0.11	1.12
VOC	0.19	1.84	0.03	0.25

4.1.17. The permittee shall comply with the emission limitations set forth below on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated or 180 days after initial startup, whichever comes first. **[40CFR §60.102a (a), NSPS Subpart Ja]**

i. The permittee shall not burn in any fuel gas combustion device any fuel gas that contains H2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. **[40CFR §60.102a (g)(1)(ii), NSPS Subpart Ja]**

4.1.18. The permittee is subject to the design, equipment, work practice or operational standards as specified in 40 CFR §60.103a. **[40CFR §60.103a, NSPS Subpart Ja]**

4.1.19. The permittee shall conduct a performance test to demonstrate initial compliance with each applicable emissions limit in §60.102a according to the requirements of §60.8. The notification requirements of §60.8(d) apply to the initial performance test and to subsequent performance tests, but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments. **[40CFR §60.104a, NSPS Subpart Ja]**

Heaters H-201, H-441, and H-701

4.1.20. Emissions from heaters H-201, H-701, and H-441 shall not exceed those listed in the following table. Compliance with the SO_2 limit for H-701 and H-441 shall demonstrate compliance with the less stringent limit of 45CSR§10-3.1.e.

Pollutant	H-201		H-701		H-441	
	TPM	TPY	TPM	TPY	TPM	TPY
CO	0.43	2.38	0.44	4.36	0.44	4.44
NO_x	0.28	2.78	0.11	1.06	0.53	5.28
PM	0.02	0.22	0.04	0.39	0.04	0.40
SO_2	0.08	0.77	0.14	1.40	0.01	0.03
VOC	0.02	0.16	0.03	0.29	0.03	0.29

4.1.21. Heaters H-441 shall be limited to combusting natural gas only.

Heaters H-500S and H-600S

4.1.22. Emissions from H-500S and H-600S heaters shall not exceed those listed in the following table. Note: "S" means multiple heaters with emissions exiting a common emission point.

Pollutant	H-500S		H-600S	
	TPM	TPY	TPM	TPY
CO	2.02	20.16	1.5	15.01
NO_x	2.96	29.58	2.14	21.44
PM	0.19	1.90	0.14	1.36
PM_{10}	0.18	1.80	n/a	n/a
$PM_{2.5}$	0.18	1.76	n/a	n/a
SO_2	0.72	7.21	0.48	4.83
VOC	0.13	1.31	0.1	0.98

Heaters H-901 and H-1101

4.1.23. Emissions from the DHT Heater (H-901) and Hydrogen Plant Heater (H-1101) shall not exceed those listed in the following table.

Pollutant	H-901		H-1101	
	TPM	TPY	TPM	TPY
CO	0.42	4.22	0.17	1.70

NO_x	0.30	3.01	0.68	6.80
PM	0.08	0.79	0.17	1.70
SO_2	0.27	2.72	0.01	0.10
VOC	0.12	1.20	0.13	1.25

4.1.24. Heater H-1101 shall be limited to combusting natural gas only.

Boilers A, B, and C, Heaters, H-201, H-500S, H-600S, H-701, and H-901

4.1.25. No owner or operator shall burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The listed heaters and boilers are affected facilities, as that term is used in 40 CFR 60, Subparts A and J. **[40C.F.R.§60.104(a)(1), NSPS Subpart J]**

4.1.26. The permittee shall comply with the emission limitations set forth in 40 CFR 60 Subpart J on and after the date on which the initial performance test, required by §60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first. **[40 C.F.R. § 60.104, NSPS Subpart J and 45CSR §16-4.1]**

4.2. Monitoring Requirements

All Boilers and Heaters

4.2.1. Visual emission checks of each emission point subject to an opacity limit shall be conducted during periods of normal facility operation for a sufficient time interval to determine if the unit has visible emissions using 40 CFR 60 Appendix A, Method 22. If natural gas is being combusted, the visual emissions checks shall be conducted monthly. If fuel oil is being combusted, the visual emissions checks shall be conducted weekly. If visible emissions are identified during the survey, or at any other time, the permittee shall take corrective action to minimize the emissions immediately. If during these checks, or at any other time, visible emissions are observed, a visible emission evaluation shall be conducted in accordance with 40 CFR 60 Appendix A, Method 9. A Method 9 evaluation shall not be required if the visible emission condition is corrected in a timely manner. A record of each visible emission check required above shall be maintained on site for a period of no less than five (5) years. Said record shall include, but not be limited to, the date, time, name of emission unit, the applicable visible emissions requirement, the results of the check, what action(s), if any, was/were taken, the name of the observer, and any data required by 40 CFR 60 Appendix A, Method 22 or Method 9.

Boilers A and B, H-201, H-600S

4.2.2. To demonstrate compliance with permit condition 4.1.25, the permittee shall install, certify, calibrate, maintain, and operate a fuel gas CEMS in accordance with the requirements of 40 CFR 60.11, 60.13, and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. **[40 C.F.R. § 60.105(1)(3), NSPS Subpart J]**

4.2.3. To demonstrate compliance with the three-hour average NOx limit of permit condition 4.1.13 of this permit, the permittee shall install, certify, calibrate, maintain, and operate a CEMS on Boilers A and B to measure NOX and O2 in accordance with the requirements of 40 CFR 60.11, 60.13, and Part 60, Appendices A and F.

Heater H-901 and H-1101

4.2.4. Compliance with the hydrogen sulfide concentration limit for H-901 of permit condition 4.1.25 shall be demonstrated using the continuous monitor as follows:

4.2.4.1. An instrument for continuously monitoring and recording the concentration (dry basis) of H2S in fuel gases before being burned in any fuel gas combustion device.

4.2.4.2. The span value for this instrument is 425 mg/dscm H2S.

4.2.4.3. Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned.

4.2.4.4. The performance evaluations for this H2S monitor under §60.13(c) shall use Performance Specification 7. Method 11, 15, 15A, or 16 shall be used for conducting the relative accuracy evaluations.
[40 C.F.R. §60.105(a)(4)(i)(ii)(iii) and 45CSR §16-4.1]

4.2.5. The permittee shall monitor the amount of natural gas consumed in H-1101 using flow meters.

4.2.6. The permittee shall monitor the amount of fuel gas consumed in H-901 using flow meters.

Heaters H-101R, H-102R, H-500S, and H-501R

4.2.7. To demonstrate compliance with the emissions limitations requirements of 40 CFR § 60.102a and permit condition 4.1.17, the permittee shall continuously monitor the concentration of H2S in refinery fuel gas consumed by the heaters and meet the monitoring of emissions and operations for fuel gas combustion devices. **[40 CFR §60.107a(a)(2), NSPS Subpart Ja]**

4.3. Testing Requirements

Heaters H-101R

4.3.1. The permittee is subject to the performance test requirements established in 40 CFR §60.104a. **[40 CFR §60.104a, NSPS Subpart Ja]**

4.4. Recordkeeping Requirements

4.4. 1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4. 2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4. 3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

All Boilers and Heaters

4.4. 4. To determine compliance with restrictions set forth in Section 4.1.4., the permittee shall document the frequency, length of time, amount of fuel oil consumed, and estimate of emissions during DOT maintenance and periods of natural gas curtailment in which fuel oil was combusted. To determine compliance with fuel oil sulfur content limits set forth in Section 4.1.4., the permittee shall keep records of the sulfur content of all fuel oil received for the purpose of combustion. Each batch of fuel oil shall have its sulfur content determined by test method ASTM D4294. This information along with appropriate emission factors from *EPA's AP-42 Fifth Edition, Volume I, Supplement E, Chapter 1.3* may be used to estimate emissions.

All Boilers and Heaters Except H-201

4.4. 5. The operators of fuel burning units shall maintain a periodic exception report for each unit. Such reports shall include, but may not be limited to the date and time of start-ups and shutdowns. All such requirements, including notification by telephone, telefax, or other such method determined by the Director, shall be deemed to be satisfied when the reports are maintained on site for a period of no less than five (5) years and shall be made available upon request to the Director or his/her duly authorized representative.
[45CSR§2-8.3.b.]

4.4. 6. The permittee shall maintain records of the operating schedule and the quantity of fuel consumed in each fuel burning unit monthly, at a minimum, but may record it more often at the discretion of the permittee.
[45CSR§2-8.3.c.]

Boilers A, B and C, Heaters H-101R, H-102R, H-501R, H-500S, H-600S and H-701

4.4. 7. The owner or operator of fuel burning unit(s), manufacturing process source(s) or combustion source(s) subject to 45CSR§§10-3, 4 or 5 shall maintain on-site a record of all required monitoring data as established in a monitoring plan pursuant to 45CSR§10-8.2.c. Such records shall be made available to the Director or his duly authorized representative upon request. Such records shall be retained on-site for a minimum of five years. **[45CSR§10-8.3.a.]**

4.4. 8. The owner or operator of a fuel burning unit(s) or a combustion source(s) shall maintain records of the operating schedule and the quantity and quality of fuel consumed in each unit in a manner specified by the Director. Such records are to be maintained on-site and made available to the Director or his duly authorized representative upon request. **[45CSR§10-8.3.c.]**

Boilers A and B

4.4. 9. To determine compliance with the emission limits set forth for Boiler A and Boiler B set forth in Section 4.1.13, the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the two boilers, individually. This information along with appropriate emission factors from EPA's Supplement D, Chapter 1.4 may be used to estimate monthly emissions of all pollutants except SO_2.

Boiler C

4.4. 10. To determine compliance with the emission limits for Boiler C, set forth in Section 4.1.14., the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within Boiler C and the hours of operation. This information along with appropriate emission factors from *EPA's Compilation of Air Pollutant Emission Factors AP-42 Fifth Edition, Volume I, Supplement D: Stationary Point and Area Sources* (AP-42), Chapter 1.4. may be used to estimate monthly emissions of all pollutants except NO_x. The emission factor for NO_x shall be 0.050 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total.

Heaters H-101R and H-102R, H-701 and H-441, H-201, H-501R, H-500S , H-600S

4.4. 11. To determine compliance with the emission limits set forth for H-101R, H-102R, and H-501R set forth in Section 4.1.16, the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within both heaters for H-101R and H-102R and individually for H-501R. This information along with appropriate emission factors from *EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4.* may be used to estimate monthly emissions of all pollutants except NO_x and SO_2. SO_2 emission factors shall be based on the 1995 SO_2 SIP and heating value (HHV) of 1019 Btu/scf, which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total. Compliance with the SO_2 limit shall demonstrate compliance with the less stringent requirement of CO-SIP-95-1 - Condition IV.4. (SIPed) and 45CSR§10-3.1.e.

4.4. 12. To determine compliance with the emission limits set forth for H-441 set forth in Section 4.1.20., the permittee shall keep monthly records of the amount of natural gas consumed in the two heaters. This information along with appropriate emission factors from *EPA's AP-42 Fifth Edition, Volume I, Supplement D, Chapter 1.4* may be used to estimate monthly emissions.

4.4. 13. To determine compliance with the emission limits set forth for H-201, H-500 Series, H-600 Series, and H-701set forth in Sections 4.1.20 and 4.1.22, the permittee shall keep monthly records of the amount of fuel gas (refinery plus natural gas) consumed within the three heaters, individually. This information along with appropriate emission factors from *EPA's Supplement D, Chapter 1.4.* may be used to estimate monthly emissions of all pollutants except SO_2. SO_2 emission factors shall be based on the 1995 SIP and heating value (HHV), which sets a limit of 0.13260 lb/MMBtu. Compliance with the yearly limit shall be based on a 12-month rolling total.

All Boilers and Heaters Except H-441 and H-1101

4.4. 14. For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.
[40 C.F.R. §60.107(d), NSPS Subpart J and 45CSR §16-4.1]

Heaters H-901 and H-1101

4.4. 15. The permittee shall keep monthly records of the amount of refinery fuel gas consumed by H-901. To determine compliance with NOx, SO2, VOC, and CO emissions limits for the H-901, emission factors from manufacturer's specifications along with fuel gas consumption may be used. To determine compliance with the PM emission limits, AP-42 emission factors Table 1.4.-2 (1998) along with fuel gas consumption data may be used. Said records shall be maintained on-site for a period of (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.

4.4. 16. The permittee shall maintain continuous record for the H2S concentration in the refinery fuel gas consumed by H-901. Said records shall be maintained on-site for a period of (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.

4.4. 17. The permittee shall keep monthly records of the amount of natural gas consumed by H-1101. To determine compliance with the NOx, SO2, and CO emission limits for the H-1101, the permittee may use manufacturer's specifications and natural gas consumption. To determine compliance with the VOC and PM emission limit, natural gas consumption date and AP-42 Table 1.4-2 (1998) using an average gas high heating value (HHV) of 1020 Btu/scf may be used. Said records shall be maintained on-site for a period of (5) years. Said records shall be made available to the Director of the Division of Air Quality or his/her duly authorized representative upon request and shall be certified by a responsible official upon the submittal.

Heaters H101R , H-102R, H-500S, and H-501R

4.4. 18. Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section. **[40 CFR §60.108a, NSPS Subpart Ja]**

4.5. Reporting Requirements

All Boilers, Heaters H-101R, H-102R, H-441, H-701, H-501R, H-500S, H-600S, H-901, H-1101

4.5.1. The owner or operator of a fuel burning unit(s) subject to 45CSR2 shall report to the Director any malfunction of such unit or its air pollution control equipment which results in any excess particulate matter emission rate or excess opacity (i.e., emissions exceeding the standards in 45CSR§§2-3 and 4) as provided in one of the following subdivisions:

a. Excess opacity periods meeting the following conditions may be reported on a quarterly basis unless otherwise required by the Director:

1. The excess opacity period does not exceed thirty (30) minutes within any 24-hour period; and

2. Excess opacity does not exceed 40%.

b. The owner or operator shall report to the Director any malfunction resulting in excess particulate matter or excess opacity, not meeting the criteria set forth in 45CSR§2-9.3.a, by telephone, telefax, or e-mail by the end of the next business day after becoming aware of such condition. The owner or operator shall file a certified written report concerning the malfunction with the Director within thirty (30) days providing the following information:

1. A detailed explanation of the factors involved or causes of the malfunction;
2. The date and time of duration (with starting and ending times) of the period of excess emissions;
3. An estimate of the mass of excess emissions discharged during the malfunction period;
4. The maximum opacity measured or observed during the malfunction;
5. Immediate remedial actions taken at the time of the malfunction to correct or mitigate the effects of the malfunction; and
6. A detailed explanation of the corrective measures or program that will be implemented to prevent a recurrence of the malfunction and a schedule for such implementation. **[45CSR§2-9.3.]**

<u>Boilers A and B, Heaters H-101R, H-102R, H-501R, H-500S, H-600S, H-901</u>

4.5.2. The owner or operator shall submit a periodic exception report to the Director, in a manner specified by the Director. Such an exception report shall provide details of all excursions outside the range of measured emissions or monitored parameters established in an approved monitoring plan (see Appendix A) and shall include, but not be limited to, the time of the excursion, the magnitude of the excursion, the duration of the excursion, the cause of the excursion and the corrective action taken. **[45CSR§10-8.3.b.]**

<u>Boiler C</u>

4.5.3. The permittee is responsible for submitting notification of the date of construction or reconstruction, anticipated startup, and actual startup and complying with 40 C.F.R. § 60.40c, 40 C.F.R. § 60.48c, and 40 C.F.R. § 60.8. The permittee has complied with this requirement by submitting notification. Renotification will be required if modifications are made.
[40 C.F.R. § 60.48c and 45CSR§16-2.1.]

<u>Heater H-901 and H-1101</u>

4.5.4. For any periods for which sulfur dioxide or oxides emissions data are not available for H-901, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability. **[40 C.F.R. §60.107(d), NSPS Subpart J and 45CSR §16-4.1]**

<u>Heaters H-101R, H-102R, H-500S, and H-501R</u>

4.5.5. Each owner or operator subject to the emissions limitations in §60.102a shall comply with the notification, recordkeeping, and reporting requirements in §60.7 and other requirements as specified in this section. **[40 C.F.R. §60.108a, NSPS Subpart Ja]**

5.0. Source-Specific Requirements [Loading Operations, Flares and Thermal Oxidizers: F1, T Load, MLD, OXIDIZER, MLDOX, and NH3OX]

5.1. Limitations and Standards

5.1.1. Emissions shall not exceed those listed in the table below. Annual emission limits are based on a 12-month rolling basis.

Emission Point ID	Regulated Pollutant	Emission Limit	
		TPM	TPY
F1 (pilot light)	CO	0.007	0.074
	NOX	0.009	0.088
	VOC	0.001	0.005
	$PM_{2.5}/PM_{10}/PM$	0.001	0.007
F2 (pilot light)	CO	0.013	0.129
	NOX	0.015	0.153
	VOC	0.001	0.008
	$PM_{2.5}/PM_{10}/PM$	0.001	0.012
TLOAD OXIDIZER	VOC	1.57	15.77
	Benzene	0.03	0.26
	Total HAPs	0.27	2.68
	CO	0.20	1.98
	NOX	0.04	0.36
	PM	0.01	0.04
	PM10	0.01	0.04
	PM2.5	0.01	0.04
	SO2	0.02	1.16
MLD MLDOX	VOC	1.09	10.86
	Benzene	0.01	0.05
	Total HAPs	0.11	1.05
	CO	0.27	2.63
	NOX	0.05	0.48
	PM	0.01	0.05
	PM10	0.01	0.05
	PM2.5	0.01	0.05

	SO2	0.08	0.72
NH3OX	VOC	0.10	1.00
	NOX	0.05	0.50
	CO	0.80	7.96
	SO2	0.01	0.02
	PM	0.02	0.22
	PM10	0.02	0.22
	PM2.5	0.02	0.22

5.1.2. The permittee shall not exceed the annual limits in the table below that correspond to the emission limits established in requirement 5.1.1. Annual quantities are based on a 12-month rolling basis.

Throughput Limits		
Location	Product	Quantity (Mgal/year)
Marine Loading	Gasoline	40,387
	Light Crude Oil (including oil with a vapor pressure up to 11.0 psia)	306,600
	Diesel	37,065
	Kerosene	46,000
	Lube Oil/ Heavy Products	30,660
Truck Loading	Diesel	134,904
	Gasoline	96,960
	No. 6 Fuel Oil	13,650
	Kerosene	15,330
	Lube Oil/ Heavy Products	136,920
Operational Limits		
Location	Product	Quantity
Main/Sour Gas Flare [F1]	Non-Pilot emissions	250 hours

5.1.3. During truck loading of gasoline, VOC emissions shall be controlled by the Loading Rack Thermal Oxidizer [OXIDIZER/ 00A-02].

5.1.4. Marine Loading.

a. During marine loading of gasoline and light crude oil, VOC emissions shall be controlled by the

Marine Barge Loading Thermal Oxidizer [MLDOX/ 00A-04]. MLDOX shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 98% for VOCs.

b. All vessels loaded from the Marine Loading Dock (MLD) shall be submerged filled.

5.1.5. Emissions from the Ammonia Destruction Unit (ADU) shall be routed to the ADU Thermal Oxidizer [NH3OX/00A-05] at all times that the ADU is in operation. The thermal oxidizer [NH3OX] shall be operated within the operating parameters established during testing and shall be maintained to achieve a minimum control efficiency of 99.9% for VOCs.

5.1.6. The Main Flare [F1/00A-01], the Sour Gas Flare [F2/00A-03], the Truck Loading Thermal Oxidizer [OXIDIZER/00A-02], the Marine Loading Thermal Oxidizer [MLDOX/00A-04], and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX], are subject to the requirements of 45CSR6 including but not limited to the following:

a. No person shall cause, suffer, allow or permit particulate matter to be discharged from any incinerator into the open air in excess of the quantity determined by the use of the following formula:

Emissions(lb/hr) = F x Incinerator Capacity (tons/hr)
where the factor, F, is as indicated in the table below:

Incinerator Capacity	F Factor
Less than 15,000 lbs/hr	5.43
15,000 lbs/hr or greater	2.72

Calculation for PM Emissions:

F1 [00A-01] and F2 [00A-03]:

$$(2.72) * \left(395{,}000\ \frac{lb}{hr}\right) * \left(\frac{ton}{2000\ lb}\right) \qquad = 537.2\ lb/hr$$

OXIDIZER [00A-02]:

$$(5.43) * \left(64.8\ \frac{lb}{hr}\right) * \left(\frac{ton}{2000\ lb}\right) \qquad = 0.176\ lb/hr$$

MLDOX [00A-04]:

$$(5.43) * \left(4600\ \frac{lb}{hr}\right) * \left(\frac{ton}{2000\ lb}\right) \qquad = 12.5\ lb/hr$$

NH3OX [00A-05]:

(5.43) * (416.08 lb/hr) * (ton/2000 lb) = ***1.13 lb/hr***

[45CSR§6-4.1]

b. No person shall cause, suffer, allow or permit emission of smoke into the atmosphere from any incinerator which is twenty (20%) percent opacity or greater.
[45CSR§6-4.3]

c. Incinerators, including all associated equipment and grounds, shall be designed, operated and maintained so as to prevent the emission of objectionable odors.
[45CSR§6-4.6]

5.1.7. The permittee shall not cause, suffer, allow, or permit the emission into open air from any source operation an in-stack sulfur dioxide concentration exceeding 2000 ppm by volume from existing source operations. Note: "In-stack" concentration as interpreted for a flare means the exhaust concentration after combustion. **[45CSR§10-4.1]**

5.1.8. *Reserved*

5.1.9. For the Main Flare [F1], the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H_2S) in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit. **[NSPS, Subpart Ja; 40 CFR §60.103a(h)]**

5.1.10. For the Sour Gas Flare [F2], the owner or operator shall not burn in any affected flare any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf) determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph. **[NSPS, Subpart J; 40 CFR §60.104(a)(1)]**

5.1.11. *Reserved*

5.1.12. *Reserved*

5.1.13. The Main Flare [F1] is an affected facility as that term is used in 40 CFR Part 60. The Main Flare [F1] is subject to the requirements of 40 CFR Part 60, Subparts A and Ja. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR 60.11(d).

5.1.14. The Sour Gas Flare [F2] is an affected facility as that term is used in 40 CFR Part 60. The Sour Gas Flare [F2] is subject to the requirements of 40 CFR Part 60, Subparts A and J. The permittee shall comply with the NSPS obligation to implement good air pollution control practices as required by 40 CFR 60.11(d).

5.1.15. The Main Flare [F1] shall comply with the applicable work practice standards of NSPS, Subpart Ja. **[NSPS, Subpart Ja; 40 CFR §60.103a]**

5.1.16. The permittee shall implement a program to investigate the cause of Acid Gas Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Acid Gas Flaring Incidents, and minimize Acid Gas Flaring Incidents. The permittee shall evaluate whether Acid Gas Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets for the Root Cause and all contributing causes of the Acid Gas Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Acid Gas Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.

- "Acid Gas Flaring Incident' means the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five-hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the AG Flaring Incident. "Acid Gas" means any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of amine solution.
- "Acid Gas Flaring" means the combustion of Acid Gas and/or Sour Water Stripper Gas in an Acid Gas Flaring Device. "Acid Gas Flaring Device" shall mean any device at EWVI that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The Acid Gas Flaring Device currently in service at EWVI is F2 [00A-03].
- "Sour Water Stripper Gas" shall mean the gas produced by the process of stripping refinery sour water.
- "Root Cause" means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.
- "Malfunction" means, as specified in 40 CFR Part 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

5.1.17. In response to any Acid Gas or Hydrocarbon Flaring Incident from the Sour Gas Flare [F2], the permittee shall take, as expeditiously as practicable, such interim and/or long-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that Acid Gas or Hydrocarbon Flaring Incident.

5.1.18. The permittee shall implement a program to investigate the cause of Hydrocarbon Flaring Incidents from the Sour Gas Flare [F2], take reasonable steps to correct the conditions that have caused or contributed to Hydrocarbon Flaring Incidents, and minimize Hydrocarbon Flaring Incidents. The permittee shall evaluate whether Hydrocarbon Flaring Incidents are due to Malfunctions by conducting a detailed analysis that sets forthe the Root Cause and all contributing causes of the Hydrocarbon Flaring Incident, to the extent determinable; and by conducting an analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Hydrocarbon Flaring Incident resulting from the same Root Cause or contributing causes in the future. The analysis should evaluate the alternatives, if any, that are available, the probable effectiveness and the cost of the alternatives, and whether or not an outside consultant should be retained to assist in the analysis. Possible design, operation, and maintenance changes shall be evaluated.

- "Hydrocarbon Flaring Incident' means the continuous or intermittent Hydrocarbon Flaring, except for Acid Gas and/or Sour Water Stripper Gas, at a Hydrocarbon Flaring Device that results in the emission of sulfur dioxide equal to, or in excess of five-hundred (500) pounds in any twenty-four (24) hour period; provided, however, that if five-hundred (500) pounds or more of sulfur dioxide have been emitted in a twenty-four (24) hour period and Flaring continues into subsequent, contiguous, non overlapping twenty-four (24) hour period(s), each period of which results in emissions equal to, or in excess of five-hundred (500) pounds of sulfur dioxide, then only one Hydrocarbon Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the Hydrocarbon Flaring Incident.

- "Hydrocarbon Flaring" means the combustion of refiner-generated gases, except for Acid Gas and/or Sour Water Stripper Gas in a Hydrocarbon Flaring Device.
- "Hydrocarbon Flaring Device" means a flare device used to control (through combustion) any excess volume of a refinery generated gas other than Acid Gas and/or Sour Water Stripper Gas.
- "Root Cause" means the primary cause(s) of an AG Flaring Incident(s) and/or Hydrocarbon Flaring Incident(s) as determined through a process of investigation.
- "Malfunction" means, as specified in 40 CFR Part 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

5.2. Monitoring Requirements

5.2.1. The permittee shall monitor the PM emissions by conducting visible emissions checks in accordance with Section 4.2.1. of this permit.

5.2.2. To determine compliance with the emission rate limits set forth in Section 5.1.1, the permittee shall monitor hours of operation for pilot and non-pilot conditions of the Main Flare [F1], and the Ammonia Destruction Unit Thermal Oxidizer [NH3OX]. Compliance with yearly limits shall be based on a 12-month rolling basis.

5.2.3. To determine compliance with the annual emission rate limits set forth in Section 5.1.1 for the OXIDIZER and MLDOX, the permittee may estimate emissions using monthly loading records, along with the appropriate emission factors for loading losses from AP-42, Chapter 5.2 (7/08). Compliance with the yearly limit shall be based on a 12-month rolling total.

5.2.4. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.13 for MLDOX , OXIDIZER, and NH3OX. **[NSPS, Subpart A; §60.13]**.

5.2.5. The permittee shall meet all applicable monitoring requirements of 40 CFR §60.107a for F1 **[NSPS, Subpart Ja; 60.107a]**

5.3. Testing Requirements

5.3.1. The permittee shall conduct an initial performance test of MLDOX to demonstrate compliance with the control efficiency provided in the Emissions Unit Table, Section 1.0. Operating parameters shall be established in accordance with the most recent performance test.

5.3.2. The permittee shall meet all applicable performance tests requirements of 40 CFR §60.8 for MLDOX, OXIDIZER, and NH3OX. **[NSPS, Subpart A; §60.8]**

5.3.3. *Reserved*

5.3.4. The permittee shall calculate an annual estimate of HAP emissions from gasoline and light crude oil from marine tank vessel loading operations. Emission estimates and emission factors shall be based on test data, or if test data is not available, shall be based on measurement or estimating techniques generally accepted in industry practice for operating conditions at the source. **[MACT, Subpart Y; 63.560(a)(3)]**

5.4. Recordkeeping Requirements

5.4.1. To determine compliance with the loading emission limits set forth in Sections 5.1.1, the permittee shall keep a monthly record of the volume and type of each product/product type loaded at each truck loading station and marine barge loading station and whether or not the VOC emissions were controlled using the control device [OXIDIZER, or MLDOX]. AP-42 emission factors for flares and transportation and marketing of petroleum liquids (Chapter 5.2, 1/95) or test data may be used to estimate emissions.

5.4.2. To determine compliance with the annual benzene emission limit set forth in Section 5.1.1., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of benzene present in petroleum liquids processed and transported at the facility. The following equation shall be to determine monthly and yearly emissions.

Benzene Emissions (tpm or tpy) = (Total VOCs (tpm or tpy)) x (Actual Benzene Vapor Weight %)

Compliance with the yearly limit shall be based on a 12-month rolling total.

5.4.3. To demonstrate compliance with the operational limit for the main/sour gas flare [F1] established in section 5.1.2, the permittee shall maintain records of the hours that non-pilot emissions were sent to the flare. The annual limit shall be recorded on a 12-month rolling total basis.

5.4.4. The permittee shall meet all applicable notification and record keeping requirements of 40 CFR §60.7 for OXIDIZER, MLDOX, and NH3OX. **[NSPS, Subpart A; §60.7]**

5.4.5. *Reserved*

5.4.6. The permittee shall retain records of the emissions estimates determined in 40 CFR §63.565(l) and requirement 5.1.2 of this permit and their actual throughputs by commodity for gasoline and light crude oil,for 5 years. **[MACT, Subpart Y; 63.560(a)(3)]**

5.5. Reporting Requirements

5.5.1. For the Main Flare [F1], the permittee shall comply with the reporting requirements of 40 CFR 60, Subpart Ja. **[40 CFR §60.108a]**

5.5.2. For the Sour Gas Flare [F2], the permittee shall comply with the reporting requirements of 40 CFR 60, Subpart J. **[40 CFR §60.107(f)]**

5.5.3. The permittee shall meet all applicable reporting requirements of 40 CFR §60.19 for OXIDIZER, MLDOX, and NH3OX. **[NSPS, Subpart A; §60.19]**

6.0. Source-Specific Requirements [Process Units: CDU, MEK-TOL, DHT-FUG, ISOM, UNIFINER, ADU, PL-FUG, and YNGL-FUG]

6.1. Limitations and Standards

6.1.1. Crude oil charge rate into the crude oil distillation unit shall not exceed 839,500 barrels per month and 8,395,000 barrels per year.

6.1.2. Fugitive emissions of VOC's (MEK and Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 9.29 TPY. Fugitive emissions of HAPs (Toluene) from the Solvent Dewaxing Unit (Emission Point ID No. MEK-TOL) shall not exceed 4.65 TPY.

6.1.3. The facility shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions:

a. Leak Definition for Valves. The facility shall utilize an internal leak definition of 500 ppm VOCs for the Refinery valves, excluding pressure relief devices. This leak definition for valves will be effective 120 days after issuance of the permit.
b. Leak Definition for Pumps. The facility shall utilize an internal leak definition of 2000 ppm VOCs for the Refinery pumps by the following dates:

1. By no later than June 30, 2004, the facility shall utilize this definition for 50% of the total number of pumps that each of them has at the Covered Refinery;
2. By no later than December 31, 2004, The facility shall utilize this definition for 85% of the total number of pumps that each of them has at the Covered Refinery;
3. By no later than April 30, 2006, The facility shall utilize this definition for all of the pumps that each of them has at the Covered Refinery.

6.1.4. Fugitive emissions from the Diesel Hydrotreater [DHT-FUG], the Ammonia Destruction Unit [ADUFUG], the Platformer Expansion Unit [PL-FUG], and the Y-Grade NNL Unit [YNGL-FUG] shall not exceed the following:

Pollutant	DHT-FUG Fugitives	ADUFUG Fugitives	PL-FUG Fugitives	YNGL-FUG Fugitives
	ton/yr	ton/yr	ton/yr	ton/yr
VOC	13.20	0.34	0.60	0.94
Toluene	0.003	n/a	n/a	n/a
Ethyl Benzene	0.001	n/a	n/a	n/a
Xylene	0.04	n/a	n/a	n/a
Pentane	n/a	0.05	n/a	n/a
Hexane	n/a	0.02	0.04	0.03

6.1.5. Fugitive emissions from the ISOM Unit shall not exceed 3.72 tpy VOC's and 0.85 tpy total HAP's.

6.1.6. The permittee shall comply with the VOC equipment leak requirements of NSPS, Subpart VVa (as required by the applicability of Subpart GGGa) of affected facilities for which construction, reconstruction, or modification commenced after November 7, 2006 and section 8.0 of this permit.

6.2. Recordkeeping Requirements

6.2.1. To determine compliance with the crude oil charge rate limits set forth in Section 6.1.1., the permittee shall keep daily records along with monthly and yearly totals of the amount of crude oil charged to the crude oil distillation unit. Compliance with the yearly limit shall be based on a 12-month rolling total.

6.2.2. To determine compliance with VOC fugitive emission rate limits set forth in Section 6.1.2., 6.1.4., 6.1.5., and the internal leak definitions set forth in Section., 6.1.3, the permittee shall comply with the requirements of 40CFR60 Subpart VV and apply the following Leak Detection and Repair (LDAR) program enhancements:

a. Emission Estimates. The permittee may use an enhanced LDAR program for controlling and estimating emissions on a monthly and yearly basis for the Solvent Dewaxing Unit. The permittee may use EPA's Correlation Approach, published in EPA's Protocol for Equipment Leak Emission Estimates, with measured screening values and hours of operation to determine compliance with the emission limits.

7.0. Source-Specific Requirements [Tank Emissions and Throughput Rates]

7.1. Limitations and Standards

7.1.1. Storage tanks are limited to the raw material/ product type and throughput provided in the table below:

Tank ID No.	Raw Material/Product Type and Throughput (gallons per year)
4000, 4001, 4060, and 4061	crude oil-(802,264,890)
4062, 4063	light crude oil w/vapor pressure up to 11.0 psia (306,600,000)
4004, 4005, 4006, 4012, 4013, 4014, 4015, 4016, 4050, 4052, and 4053	gasoline or ethanol (282,320,300)
4002, 4003, 4009, 4011, 4054, 4055, 4056, and 4057	heavy products or kerosene 406,459,760
4007, 4008, 4010, 4017, 4018, 4019, 4020, 4021, 4022, 4023, 4024, 4025, 4026, 4027, 4028, 4029, 4030, 4031, 4032, 4033, 4034, 4035, 4036, 4037, 4038, 4039, 4040, 4041, 4042, 4043, 4044, 4045, 4046, 4047, 4048, 4051, 4103, and 4104	heavy products (550,817,989)

7.1.2. Combined emissions from the tanks listed in section 7.1.1 shall not exceed the following:

Pollutant	Emission Rate	
	TPM	TPY
Total VOC	5.39	53.87
Benzene	0.08	0.81
Total HAP	0.65	6.54

7.1.3. Fixed roof **Tanks 4012 and 4013** shall be equipped with internal floating roofs to minimize emissions of VOC's.

7.1.4. The following requirements apply to **Tanks 4004, 4005, 4006, 4014, 4015, and 4016**:

a. Each and every slotted guidepole that passes through the floating roof shall be equipped with one of the following: a pole float system; an alternate control technology that has an emission factor less than or equal to the emission factor for a pole float system; a pole sleeve system; an internal sleeve emission control system; a solid guidepole system; a flexible enclosure system; or

b. In the alternative, the Permittee may elect to:

1. cover an external floating roof tank with a fixed roof mounted on the tank above the external floating roof, or

2. remove the tank from the service storing liquids subject to NSPS Ka or Kb, modify the permit for that tank, and represent to the West Virginia Division of Air Quality that the tank will not be used to store certain petroleum liquids or volatile organic liquids.

c. For systems that use a sliding cover, the sliding cover shall be in place over the slotted-guidepole opening in the floating roof at all times, except, when the sliding cover must be removed for access. If the control technology used includes a guidepole float, the float shall be floating within the guidepole at all times except when it must be removed for access to the stored liquid or when the tank is empty.

d. The permittee shall visually inspect the deck fitting for the slotted guidepole at least once every ten (10) years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device has defects, or if a gap that is more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material.

e. Tanks taken out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are taken out of service. Tanks taken out of service must have in place, prior to being put back into service, all controls necessary to remain below the emission limits set forth by the current version of the permit.

7.1.5. The following requirements apply to **Tanks 4000, 4002, and 4003**:

a. Each and every slotted guidepole that passes through the floating roof shall be equipped with one of the following: a pole float system; an alternate control technology that has an emission factor less than or equal to the emission factor for a pole float system; a pole sleeve system; an internal sleeve emission control system; a solid guidepole system; a flexible enclosure system; or

b. In the alternative, the Permittee may elect to:

1. cover an external floating roof tank with a fixed roof mounted on the tank above the external floating roof, or

2. remove the tank from the service storing liquids subject to NSPS Ka or Kb, modify the permit for that tank, and represent to the West Virginia Division of Air Quality that the tank will not be used to store certain petroleum liquids or volatile organic liquids.

c. For systems that use a sliding cover, the sliding cover shall be in place over the slotted-guidepole opening in the floating roof at all times, except, when the sliding cover must be removed for access. If the control technology used includes a guidepole float, the float shall be floating within the guidepole at all times except when it must be removed for access to the stored liquid or when the tank is empty.

d. The permittee shall visually inspect the deck fitting for the slotted guidepole at least once every ten (10) years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device has defects, or if a gap that is more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material.

e. Tanks taken out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are taken out of service. Tanks taken out of service must have in place, prior to being put back into service, all controls necessary to remain below the emission limits set forth by the current version of the permit.

7.1.6. The following requirements apply to **Tanks 4035, 4036, 4037, 4038, 4039, and 4041:**

The owner or operator of any storage vessel to which 40 C.F.R. Part 60 subpart K applies shall store petroleum liquids as follows: if the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

7.1.7. The following requirements apply to **Tanks 4000, 4001, 4004, 4006, 4014, 4015, 4018, 4034, 4048, 4050, 4054, 4056, 4057, 4052, 4053, 4060, 4061, 4062, and 4063:**

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in 40 C.F.R. § 60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in 40 C.F.R. § 60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in 40 C.F.R. part 60, subpart VV, § 60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (40 C.F.R. § 60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) above as provided in 40 C.F.R. § 60.114b.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m^3 which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in 40 C.F.R. § 60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in 40 C.F.R. § 60.114b of this subpart.
[NSPS, Subpart Kb; 40 C.F.R. § 60.112b(a) and (b) and 45CSR§16-2.1.]

7.2. Monitoring Requirements

7.2.1. Compliance with Sections 7.1.4 and 7.1.5 may be determined by visual inspection by the Director or a duly authorized representative of the Director.

7.2.2. The following requirements apply to **Tanks 4000, 4001, 4004, 4006, 4014, 4015, 4018, 4034, 4048, 4050, 4052, 4053, 4054, 4056, 4057, 4060, 4061, 4062, and 4063**:

The owner or operator of each storage vessel as specified in 40 C.F.R. § 60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of 40 C.F.R. § 60.112b.

(a) After installing the control equipment required to meet 40 C.F.R. § 60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For Vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in 40 C.F.R. § 60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in § 60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet 40 C.F.R. § 60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 40 C.F.R. § 60.113b(b)(4) (i) and (ii).

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in § 60.112b (a)(3) or (b)(2) (other than a flare) is exempt from § 60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under 40 C.F.R. Part 60 subpart K, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, § 60.18 (e) and (f).
[40 C.F.R. § 60.113b and 45CSR§16-2.1.]

7.3. Recordkeeping Requirements

7.3.1. To determine compliance with VOC emission limit set forth in 7.1.1., the permittee shall keep monthly records of throughput of each raw material/product for each tank. These records shall be kept individually, i.e. per tank. AP-42 emission factors for organic liquid storage tanks (Supp. D, Chapter 7.1), may be used to estimate yearly emissions.

7.3.2. To determine compliance with the short-term and annual HAP emission limits set forth in Section 7.1.1., the permittee shall estimate the emissions using a material balances calculation utilizing the vapor weight of benzene present in petroleum liquids processed and transported at the facility. The following equation shall be to determine monthly and yearly emissions.

HAP Emissions (tpm or tpy) = [(Individual HAP %) x (Actual VOC emissions, obtained from section 7.3.1. (tpm or tpy))/100

Compliance with the yearly limit shall be based on a 12-month rolling total.

7.3.3. The following requirements apply to **Tanks 4035, 4036, 4037, 4038, 4039 and 4041**:

Except as provided in 40 C.F.R. § 60.113(d), the owner or operator subject to 40 C.F.R. Part 60 subpart K shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.
[NSPS, Subpart Ka; 40 C.F.R. § 60.112(a) and 45CSR§16-2.1.]

7.3.4. The following requirements apply to **Tanks 4000, 4001, 4004, 4006, 4014, 4015, 4018, 4034, 4048, 4050, 4052, 4053, 4054, 4056, 4057, 4060, 4061, 4062, and 4063**:

The owner or operator of each storage vessel as specified in 40 C.F.R. § 60.112b(a) shall keep records and furnish reports as required by 40 C.F.R. § 60.115b paragraphs (a), (b), or (c) depending upon the control equipment installed to meet the requirements of 40 C.F.R. § 60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by 40 C.F.R. § 60.115b(c)(1), for at least 2 years. The record required by 40 C.F.R. § 60.115b (c)(1) will be kept for the life of the control equipment.

a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 61.112b(a)(1) or § 60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with § 61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in § 60.113b (b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report

will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with § 60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.
[NSPS, Subpart Kb; 40 C.F.R. § 60.115b and 45CSR§16-2.1]

7.3.5. The following requirements apply to **Tanks 4000, 4001, 4004, 4006, 4014, 4015, 4018, 4034, 4048, 4050, 4052, 4053, 4054, 4056, 4057, 4060, 4061, 4062, and 4063**:

(a) The owner or operator shall keep copies of all records required by 40 C.F.R. Part 60 Subpart Kb, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in 40 C.F.R. § 60.110b(a) shall keep readily accessible records showing the dimension and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference -- see § 60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in 40 C.F.R. §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879-83, 96, or 97 (incorporated by reference -- see 40 C.F.R. § 60.17); or

(ii) ASTM D323-82 or 94 (incorporated by reference -- see 40 C.F.R. § 60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of 40 C.F.R. § 60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.
[NSPS, Subpart Kb; 40 C.F.R. § 60.116b and 45CSR§16-2.1]

7.4. Reporting Requirements

[Reserved]

8.0. Source-Specific Requirements [Equipment Leaks]

8.1. Limitations and Standards

8.1.1. **Training.** The permittee shall implement the following training programs at the facility:

i. For personnel newly-assigned to LDAR responsibilities, EWVI shall require LDAR training prior to each employee beginning such work;

ii. For all personnel assigned LDAR responsibilities, EWVI shall provide and require completion of annual LDAR training; and

iii. For all other Refinery operations and maintenance personnel (including contract personnel), EWVI shall provide and require completion of an initial training program that includes instruction on aspects of LDAR that are relevant to the person's duties. Refresher training in LDAR shall be performed on a three year cycle.

8.1.2. **LDAR Personnel.** The permittee shall establish a program that will hold LDAR personnel accountable for LDAR performance. The permittee shall maintain a position within the facility responsible for LDAR management, with the authority to implement improvements.

8.1.3. **Internal Leak Definition for Valves and Pumps; Compressor Compliance.** The permittee shall utilize the following internal leak definitions for valves and pumps in light liquid and/or gas/vapor service, unless other permit(s), regulations, or laws require the use of lower leak definitions.

i. Leak Definition for Valves. The permittee shall utilize an internal leak definition of 500 ppm VOCs for the valves at the facility, excluding pressure relief devices.

ii. Leak Definition for Pumps. The permittee shall utilize an internal leak definition of 2000 ppm VOCs for the pumps at the facility.

8.1.4. **First Attempt at Repairs on Valves.** The permittee shall make a "first attempt" at repair on any valve that has a reading greater than 200 ppm of VOCs, excluding control valves, pumps, and components that LDAR personnel are not authorized to repair. The permittee, or its designated contractor, however, shall re-monitor, within 5 business days, all valves that LDAR personnel attempted to repair. Unless the re-monitored leak rate is greater than the applicable leak definition, no further action will be necessary.

8.1.5. **Delay of Repair.** For any equipment for which the permittee is allowed, under the applicable regulations, to place on the "delay of repair" list for repair:

i. For all equipment, the permittee shall:

a. Require sign-off by the unit supervisor or shift supervisor that the piece of equipment is technically infeasible to repair without a process unit shutdown, before the component is eligible for inclusion on the "delay of repair" list; and

b. Include equipment that is placed on the "delay of repair" list in the permittee's regular LDAR monitoring.

ii. For valves: For valves, other than control valves, leaking at a rate of 10,000 ppm or greater, the permittee shall continue to use its "drill and tap" method for fixing such leaking valves, rather than placing the valve on the "delay of repair" list, unless the permittee can demonstrate that there is a safety, mechanical, or major environmental concern posed by repairing the leak in this manner. After two unsuccessful attempts to repair a leaking valve through the drill and tap method, the permittee may place the leaking valve on its "delay of repair" list. If a new method develops for repairing such valves, the permittee will advise EPA prior to implementing such new method.

iii. For pumps: For pumps leaking at a rate of 2000 ppm or greater, the permittee shall undertake its best efforts to isolate and repair such pumps with a first attempt at fifteen (15) days.

8.1.6. Any affected facility under §60.480a (a) that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of §60.482-1a unless other permit requirements require more stringent requirements.
[NSPS, Subpart VVa; §60.480(a) and §60.482-1a]

8.2. Monitoring Requirements

8.2.1. **Reporting, Recording, Tracking, Repairing and Remonitoring Leaks of Valves and Pumps.** The permittee shall record, track, repair and re-monitor all leaks in excess of the internal leak definitions.

8.2.2. **LDAR Monitoring Frequency**

i. Pumps. The permittee shall monitor pumps on a monthly basis.

ii. Valves. The permittee shall monitor valves -- other than difficult to monitor or unsafe to monitor valves -- on a quarterly basis.

8.2.3. **Calibration/Calibration Drift Assessment**

i. Calibration. The permittee shall conduct all calibrations of LDAR monitoring equipment using methane as the calibration gas, in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21.

ii. Calibration Drift Assessment. The permittee shall conduct calibration drift assessments of LDAR monitoring equipment at the end of each monitoring shift, at a minimum. The permittee shall conduct the calibration drift assessment using, at a minimum, a 500 ppm calibration gas. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous calibration, the permittee shall re-monitor all valves that were monitored since the last calibration that had a reading greater than 100 ppm and shall re-monitor all pumps that were monitored since the last calibration that had a reading greater than 500 ppm.

8.2.4. **LDAR Audits.** The permittee shall implement at the facility the Refinery audits set forth in the following paragraphs to ensure compliance with all applicable LDAR requirements. The LDAR audits shall include, but not be limited to, comparative monitoring, records review, tagging, data management, and observation of the LDAR technicians' calibration and monitoring techniques.

i. Third-Party Audits. The permittee shall retain a contractor(s) to perform a third-party audit of the refinery's LDAR program at least once every four years.

ii. Internal Audits. The permittee shall conduct internal audits of the LDAR program. An internal audit of the refinery shall be held every four years.

iii. To ensure that an audit at the refinery occurs every two years, third-party and internal audits shall be separated by two years.

iv. Alternative. As an alternative to the internal audit, the permittee may elect to retain third-parties to undertake the internal audit, provided that an audit of the facility occurs every two (2) years.

If the results of any of the audits conducted at the facility identify any areas of non-compliance, the permittee shall implement, as soon as practicable, all steps necessary to correct the area(s) of noncompliance, and to prevent, to the extent practicable, a recurrence of the cause of the non-compliance. The permittee shall retain the audit reports generated during the audits and shall maintain a written record of the corrective actions taken at the facility in response to any deficiencies identified in any audits.

8.3. Testing Requirements

8.3.1. For affected facilities subject to the standards in §§ 60.482-1a through 60.482-11a, 60.483a, and 60.484a, the permit shall determine compliance with the standards according to the test methods and procedures provided in §60.485a. **[NSPS, Subpart VVa; §60.485a]**

8.4. Recordkeeping Requirements

8.4.1. **Adding New Valves and Pumps**. The permittee shall establish a tracking program for maintenance records (e.g., a Management of Change program) to ensure that valves and pumps added to the facility during maintenance and construction are integrated into the LDAR program.

8.4.2. When a leak is detected, the following requirements apply:

i. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

ii. The identification on a valve may be removed after it has been monitored for 2 successive months and no leak has been detected during those 2 months.

iii. The identification on equipment, except on a valve, may be removed after it has been repaired. **[40 CFR § 60.486(b)]**

8.4.3. When a leak has been detected, the following information shall be recorded in a log and kept for 2 years in a readily accessible location:

i. The instrument and operator identification numbers and the equipment identification number.

ii. The date the leak was detected and the dates of each attempt to repair the leak.

iii. Repair methods applied in each attempt to repair the leak.

iv. "Above 10,000" if the maximum instrument reading measured after each repair attempt is equal to or greater than 10,000 ppm.

v. "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

vi. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

vii. The expected date of successful repair of the leak if a leak is not repaired within 15 days.

viii. Dates of process unit shutdowns that occur while the equipment is unrepaired.

ix. The date of successful repair of the leak.
[40 CFR § 60.486(c)]

8.4.4. The following information shall be recorded in a log that is kept in a readily accessible location:

i. A list of identification numbers.

ii. A list of identification numbers for equipment that are designated for no detectable emissions. This list shall be signed by the owner or operator.

iii. A list of equipment identification numbers for pressure relief valves.

iv. The dates of each compliance test.

v. The background level measured during each compliance test.

vi. The maximum instrument reading measured at the equipment during each compliance test.

vii. A list of identification numbers for equipment in vacuum service.

viii. A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr, a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
[40 CFR § 60.486(e)]

ix. For all valves and pumps designated as unsafe-to-monitor or difficult-to-monitor:

a. A list of identification numbers for valves and pumps that are designated as unsafe-to-monitor, an explanation for each valve or pump stating why the valve or pump is unsafe-to-monitor, and the plan for monitoring each valve or pump.

b. A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.
[40 CFR § 60.486(f)]

8.4.5. Each owner or operator subject to the provision of NSPS, Subpart VVa shall comply with the recordkeeping requirements of this section. **[NSPS, Subpart VVa; § 60.486a]**

8.5. Reporting Requirements

8.5.1. Electronic Monitoring, Storing, and Reporting of LDAR Data

i. Electronic Storing and Reporting of LDAR Data. The facility will maintain an electronic database (e.g., EXCEL spreadsheet) for storing and reporting LDAR data. The electronic database shall include data identifying the date and time of the monitored event, and the operator and instrument used in the monitored event.

ii. Electronic Data Collection During LDAR Monitoring and Transfer Thereafter. The permittee shall use data loggers and/or electronic data collection devices during all LDAR monitoring. The permittee, or its designated contractor, shall use its/their best efforts to transfer, by the end of the next business day, electronic data from electronic data logging devices to the electronic database listed above. For all monitoring events in which an electronic data collection device is used, the collected monitoring data shall include a time and date stamp. The permittee may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken), and shall record, at a minimum, the identification of the technician undertaking the monitoring, the date, and the identification of the monitoring equipment. The permittee shall use its best efforts to transfer any manually recorded monitoring data to the electronic database within seven days of monitoring.

8.5.2. **QA/QC of LDAR Data** - The permittee shall ensure that monitoring data provided to the permittee by its contractors is reviewed for QA/QC before the contractor submits the data to the permittee. At least once per calendar quarter, the permittee shall perform QA/QC of the contractor's monitoring data which shall include, but not be limited to, number of components monitored per technician, time between monitoring events, and abnormal data patterns.

8.5.3. The permittee shall submit semiannual reports to the Administrator beginning six months after the initial startup date. All semiannual reports shall include the following information:

i. Process unit identification.

ii. For each month during the semiannual reporting period,

a. Number of valves for which leaks were detected.

b. Number of valves for which leaks were not repaired.

c. Number of pumps for which leaks were detected.

d. Number of pumps for which leaks were not repaired.

e. Number of compressors for which leaks were detected.

f. Number of compressors for which leaks were not repaired.

g. The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

iii. Dates of process unit shutdowns which occurred within the semiannual reporting period.

iv. Revisions to items reported in initial report if changes have occurred since the initial report or subsequent revisions to the initial report.

[40 CFR § 60.487(c)]

8.5.4. Each owner or operator subject to the provision of NSPS, Subpart VVa shall comply with the reporting requirements of §60.487a. **[NSPS, Subpart Vva; §60.487a]**

9.0. Source-Specific Requirements [Wastewater Treatment Plant - 40 C.F.R. Part 60 Subpart QQQ]

9.1. Limitations and Standards

9.1.1. a. Each owner or operator subject to the provisions of this subpart shall comply with the requirements of 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction.

b. Compliance with 40 CFR §§ 60.692-1 to 60.692-5 and with §§ 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.696.

c. 1. Stormwater sewer systems are not subject to the requirements of this subpart.

2. Ancillary equipment, which is physically separate from the wastewater system and does not come in contact with or store oily wastewater, is not subject to the requirements of this subpart.

3. Non-contact cooling water systems are not subject to the requirements of this subpart.

4. An owner or operator shall demonstrate compliance with the exclusions in paragraphs c.1., 2., and 3. of this section as provided in 40 CFR § 60.697 (h), (i), and (j).

[40 CFR § 60.692-1(a), (b), and (d) and 45CSR16]

9.1.2. **Individual drain systems.**

a. 1. Each drain shall be equipped with water seal controls.

2. Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls.

3. Each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions.

4. Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided in 40 CFR § 60.692-6.

b. 1. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter.

2. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance.

3. Junction boxes shall be visually inspected initially and semiannually thereafter to ensure that the cover is in place and to ensure that the cover has a tight seal around the edge.

4. If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided in 40 CFR § 60.692-6.

c. 1. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces.

2. The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions.

3. Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided in 40 CFR § 60.692-6.

d. Except as provided in paragraph e. of this section, each modified or reconstructed individual drain system that has a catch basin in the existing configuration prior to May 4, 1987 shall be exempt from the provisions of this section.

e. Refinery wastewater routed through new process drains and a new first common downstream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin.

[40 CFR § 60.692-2 and 45CSR16]

9.1.3. **Oil-water separators.**

a. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart shall be equipped and operated with a fixed roof, which meets the following specifications, except as provided in paragraph c. of this section or in 40 CFR § 60.693-2.

1. The fixed roof shall be installed to completely cover the separator tank, slop oil tank, storage vessel, or other auxiliary equipment with no separation between the roof and the wall.

2. The vapor space under a fixed roof shall not be purged unless the vapor is directed to a control device.

3. If the roof has access doors or openings, such doors or openings shall be gasketed, latched, and kept closed at all times during operation of the separator system, except during inspection and maintenance.

4. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps occur between the roof and wall and that access doors and other openings are closed and gasketed properly.

5. When a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.

b. Each oil-water separator tank or auxiliary equipment with a design capacity to treat more than 16 liters per second (250 gallons per minute (gpm)) of refinery wastewater shall, in addition to the requirements in paragraph a. of this section, be equipped and operated with a closed vent system and control device, which meet the requirements of 40 CFR § 60.692-5.

c. Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in 40 CFR §§ 60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, Subparts K, Ka, or Kb are not subject to the requirements of this section.

d. Slop oil from an oil-water separator tank and oily wastewater from slop oil handling equipment shall be collected, stored, transported, recycled, reused, or disposed of in an enclosed system. Once slop oil is returned to the process unit or is disposed of, it is no longer within the scope of 40CFR Part 60, Subpart QQQ. Equipment used in handling slop oil shall be equipped with a fixed roof meeting the requirements of paragraph a. of this section.

e. Each oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment that is required to comply with paragraph a. of this section, and not paragraph b. of this section, may be equipped with a pressure control valve as necessary for proper system operation. The pressure control valve shall be set at the maximum pressure necessary for proper system operation, but such that the value will not vent continuously.

[40 CFR § 60.692-3 (a), (b), (d), (e), and (f) and 45CSR16;]

9.1.4. **Alternative standards for oil-water separators.**

a. An owner or operator may elect to construct and operate a floating roof on an oil-water separator tank, slop oil tank, storage vessel, or other auxiliary equipment subject to the requirements of this subpart which meets the following specifications.

1. Each floating roof shall be equipped with a closure device between the wall of the separator and the roof edge. The closure device is to consist of a primary seal and a secondary seal.

i. The primary seal shall be a liquid-mounted seal or a mechanical shoe seal.

A. A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the separator and the floating roof. A mechanical shoe seal means a metal sheet held vertically against the wall of the separator by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

B. The gap width between the primary seal and the separator wall shall not exceed 3.8 cm (1.5 in.) at any point.

C. The total gap area between the primary seal and the separator wall shall not exceed 67 cm2/m (3.2 in.2/ft) of separator wall perimeter.

ii. The secondary seal shall be above the primary seal and cover the annular space between the floating roof and the wall of the separator.

A. The gap width between the secondary seal and the separator wall shall not exceed 1.3 cm (0.5 in.) at any point.

B. The total gap area between the secondary seal and the separator wall shall not exceed 6.7 cm2/m (0.32 in.2/ft) of separator wall perimeter.

iii. The maximum gap width and total gap area shall be determined by the methods and procedures specified in 40 CFR § 60.696(d).

A. Measurement of primary seal gaps shall be performed within 60 calendar days after initial installation of the floating roof and introduction of refinery wastewater and once every 5 years thereafter.

B. Measurement of secondary seal gaps shall be performed within 60 calendar days of initial introduction of refinery wastewater and once every year thereafter.

iv. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in paragraphs a.1.i. and ii. of this section.

2. Except as provided in paragraph a.4. of this section, each opening in the roof shall be equipped with a gasketed cover, seal, or lid, which shall be maintained in a closed position at all times, except during inspection and maintenance.

3. The roof shall be floating on the liquid (i.e., off the roof supports) at all times except during abnormal conditions (i.e., low flow rate).

4. The floating roof may be equipped with one or more emergency roof drains for removal of stormwater. Each emergency roof drain shall be fitted with a slotted membrane fabric cover that covers at least 90 percent of the drain opening area or a flexible fabric sleeve seal.

5. i. Access doors and other openings shall be visually inspected initially and semiannually thereafter to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions.

ii. When a broken seal or gasket on an access door or other opening is identified, it shall be repaired as soon as practicable, but not later than 30 calendar days after it is identified, except as provided in 40 CFR § 60.692-6.

b. An owner or operator must notify the Administrator in the report required by 40 CFR 60.7 that the owner or operator has elected to construct and operate a floating roof under paragraph a. of this section.

c. For portions of the oil-water separator tank where it is infeasible to construct and operate a floating roof, such as the skimmer mechanism and weirs, a fixed roof meeting the requirements of 40 CFR § 60.692-3(a) shall be installed.

d. Except as provided in paragraph c. of this section, if an owner or operator elects to comply with the provisions of this section, then the owner or operator does not need to comply with the provisions of 40 CFR §§ 60.692-3 or 60.694 applicable to the same facilities.

[40 CFR § 60.693-2 and 45CSR 16]

9.1.5. **Aggregate facility.**

A new, modified, or reconstructed aggregate facility shall comply with the requirements of 40 CFR §§ 60.692-2 and 60.692-3.
[40 CFR § 60.692-4 and 45CSR16]

9.1.6. **Closed vent systems and control devices.**

a. Vapor recovery systems (for example, condensers and adsorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater.

b. Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

c. 1. Closed vent systems shall be designed and operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined during the initial and semiannual inspections by the methods specified in 40 CFR § 60.696.

2. Closed vent systems shall be purged to direct vapor to the control device.

3. A flow indicator shall be installed on a vent stream to a control device to ensure that the vapors are being routed to the device.

4. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

5. When emissions from a closed system are detected, first efforts at repair to eliminate the emissions shall be made as soon as practicable, but not later than 30 calendar days from the date the emissions are detected, except as provided in 40 CFR § 60.692-6.

[40 CFR §§ 60.692-5(b), (d), and (e) and 45CSR16]

9.1.7. **Delay of repair.**

a. Delay of repair of facilities that are subject to the provisions of this subpart will be allowed if the repair is technically impossible without a complete or partial refinery or process unit shutdown.

b. Repair of such equipment shall occur before the end of the next refinery or process unit shutdown.
[40 CFR § 60.692-6 and 45CSR16]

9.2. Monitoring Requirements

9.2.1. Each owner or operator subject to the provisions of this subpart shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator.

a. Where a carbon adsorber is used for VOC emissions reduction, a monitoring device that continuously indicates and records the VOC concentration level or reading of organics in the exhaust gases of the control device outlet gas stream or inlet and outlet gas stream shall be used.

For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device (e.g., a carbon canister), the concentration level of the organic compounds in the

exhaust vent stream from the carbon adsorption system shall be monitored on a regular schedule, and the existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored on a daily basis or at intervals no greater than 20 percent of the design carbon replacement interval, whichever is greater. As an alternative to conducting this monitoring, an owner or operator may replace the carbon in the carbon adsorption system with fresh carbon at a regular predetermined time interval that is less than the carbon replacement interval that is determined by the maximum design flow rate and organic concentration in the gas stream vented to the carbon adsorption system.
[40 CFR § 60.695(a)(3)(ii) and 45CSR16]

9.3. Testing Requirements

9.3.1. Before using any equipment installed in compliance with the requirements of 40 CFR § 60.692-2, § 60.692-3, § 60.692-4, § 60.692-5, or § 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs.
[40 CFR § 60.696(a) and 45CSR16]

9.3.2. The owner or operator of each source that is equipped with a closed vent system and control device as required in 40 CFR § 60.692-5 (other than a flare) is exempt from § 60.8 of the General Provisions and shall use Method 21 to measure the emission concentrations, using 500 ppm as the no detectable emission limit. The instrument shall be calibrated each day before using. The calibration gases shall be:

a. Zero air (less than 10 ppm of hydrocarbon in air), and

b. A mixture of either methane or n-hexane and air at a concentration of approximately, but less than, 10,000 ppm methane or n-hexane.

[40 CFR § 60.696(b) and 45CSR16]

9.4. Record keeping requirements

9.4.1. Each owner or operator of a facility subject to the provisions of this subpart shall comply with the record keeping requirements of this section. All records shall be retained for a period of 2 years after being recorded unless otherwise noted.
[40 CFR § 60.697(a) and 45CSR16]

9.4.2. a. For individual drain systems subject to 40 CFR § 60.692-2, the location, date, and corrective action shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection.

b. For junction boxes subject to 40 § 60.692-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions.

c. For sewer lines subject to 40 CFR §§ 60.692-2 and 60.693-1(e), the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.692-2(c) and 60.693-1(e) when a problem is identified that could result in VOC emissions.

[40 CFR § 60.697(b) and 45CSR16]

9.4.3. For oil-water separators subject to 40 CFR § 60.692-3, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-3(a) when a problem is identified that could result in VOC emissions.
[40 CFR § 60.697(c) and 45CSR16]

9.4.4. For closed vent systems subject to 40 CFR § 60.692-5 and completely closed drain systems subject to 40 CFR § 60.693-1, the location, date, and corrective action shall be recorded for inspections required by 40 CFR § 60.692-5(e) during which detectable emissions are measured or a problem is identified that could result in VOC emissions.
[40 CFR § 60.697(d) and 45CSR16]

9.4.5. a. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded.

b. The reason for the delay as specified in 40 CFR § 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time.

c. The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shutdown shall be recorded.

d. The date of successful repair or corrective action shall be recorded.
[40 CFR § 60.697(e) and 45CSR16]

9.4.6. a. A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location.

b. The following information pertaining to the design specifications shall be kept.

i. Detailed schematics, and piping and instrumentation diagrams.

ii. The dates and descriptions of any changes in the design specifications.

c. The following information pertaining to the operation and maintenance of closed drain systems and closed vent systems shall be kept in a readily accessible location.

i. Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions shall be kept for the life of the facility. This documentation is to include a general description of the gas streams that enter the control device, including flow and volatile organic compound content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C (1,500 °F) is used to meet the 95-percent requirement, documentation that those conditions exist is sufficient to meet the requirements of this paragraph.

ii. For a carbon adsorption system that does not regenerate the carbon bed directly onsite in the control device such as a carbon canister, the design analysis shall consider the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature. The design analysis shall also establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

iii. Dates of startup and shutdown of the closed vent system and control devices required in 40CFR § 60.692 shall be recorded and kept for 2 years after the information is recorded.

iv. The dates of each measurement of detectable emissions required in 40 CFR §§ 60.692, 60.693, or 60.692-5 shall be recorded and kept for 2 years after the information is recorded.

v. The background level measured during each detectable emissions measurement shall be recorded and kept for 2 years after the information is recorded.

vi. The maximum instrument reading measured during each detectable emission measurement shall be recorded and kept for 2 years after the information is recorded.

vi. Each owner or operator of an affected facility that uses a carbon adsorber shall maintain continuous records of the VOC concentration level or reading of organics of the control device outlet gas stream or inlet and outlet gas stream and records of all 3-hour periods of operation during which the average VOC concentration level or reading of organics in the exhaust gases, or inlet and outlet gas stream, is more than 20 percent greater than the design exhaust gas concentration level, and shall keep such records for 2 years after the information is recorded.

If a carbon adsorber that is not regenerated directly onsite in the control device is used, then the owner or operator shall maintain records of dates and times when the control device is monitored, when breakthrough is measured, and shall record the date and time that the existing carbon in the control device is replaced with fresh carbon.

[40 CFR § 60.697(f) and 45CSR16]

9.4.7. For stormwater sewer systems subject to the exclusion in 40 CFR § 60.692-1(d)(1), an owner or operator shall keep for the life of the facility in a readily accessible location, plans or specifications which demonstrate that no wastewater from any process units or equipment is directly discharged to the stormwater sewer system.

[40 CFR § 60.697(h) and 45CSR16]

9.4.8. For ancillary equipment subject to the exclusion in 40 CFR § 60.692-1(d)(2), an owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which demonstrate that the ancillary equipment does not come in contact with or store oily wastewater.

[40 CFR § 60.697(i) and 45CSR16]

9.4.9. For oil-water separators subject to 40 CFR § 60.693-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR §§ 60.693-2(a)(1)(iii)(A) and (B), and shall be maintained for the time periods specified in paragraphs a. and b. below.

a. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(A), ten years after the information is recorded.
b. For inspections required by 40 CFR § 60.693-2(a)(1)(iii)(B), two years after the information is recorded.

[40 CFR § 60.697(k) and 45CSR16]

9.5. Reporting Requirements

9.5.1. Each owner or operator of a facility subject to this subpart shall submit to the Administrator within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, junction boxes, oil-water separators, and closed vent systems and control devices have been carried out in accordance with these standards. Thereafter, the owner or operator shall submit to the Administrator semiannually a certification that all of the required inspections have been carried out in accordance with these standards.
[40 CFR § 60.698(b)(1) and 45CSR16]

9.5.2. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to the Administrator.
[40 CFR § 60.698(c) and 45CSR16]

9.5.3. As applicable, a report shall be submitted semiannually to the Administrator that indicates:

Each 3-hour period of operation during which the average VOC concentration level or reading of organics in the exhaust gases from a carbon adsorber is more than 20 percent greater than the design exhaust gas concentration level or reading.

Each occurrence when the carbon in a carbon adsorber system that is not regenerated directly onsite in the control device is not replaced at the predetermined interval specified in § 60.695(a)(3)(ii).
[40 CFR §§ 60.698(d)(3) and (d)(3)(ii) and 45CSR16]

9.5.4. If compliance with the provisions of this subpart is delayed pursuant to 40 CFR § 60.692-7, the notification required under 40 CFR 60.7(a)(4) shall include the estimated date of the next scheduled refinery or process unit shutdown after the date of notification and the reason why compliance with the standards is technically impossible without a refinery or process unit shutdown.
[40 CFR § 60.698(e) and 45CSR16]

benzene. The report does not need to include a description of the controls to be installed to comply with the standard or other information required in 40 C.F.R. § 61.10(a).
[40 CFR § 61.357(a) and 45CSR34]

10.5.2. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Administrator a report that updates the information listed in Section 10.5.1.a. through c. of this permit. The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by Section 10.5.1.a. through c. is not changed in the following year, the owner or operator may submit a statement to that effect.
[40 CFR § 61.357(c) and 45CSR34]

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ______________________________, representing the period beginning ______________________ and ending ______________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] ______________________________ ______________________
(please use blue ink) Responsible Official or Authorized Representative Date

Name and Title ______________________________ ______________________
(please print or type) Name Title

Telephone No. ______________________ Fax No. ______________________

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1 This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(I) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

(ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of USEPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.